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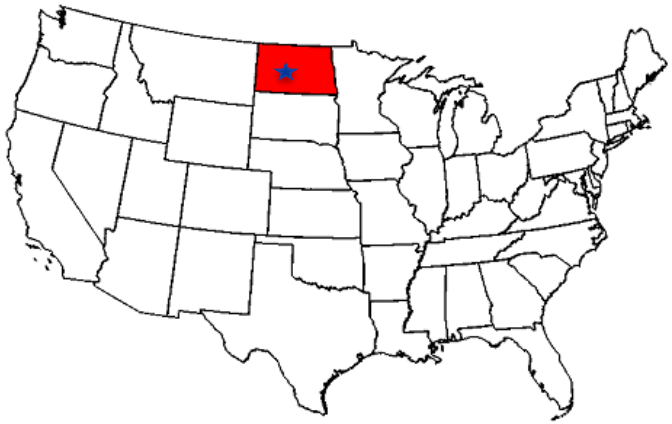
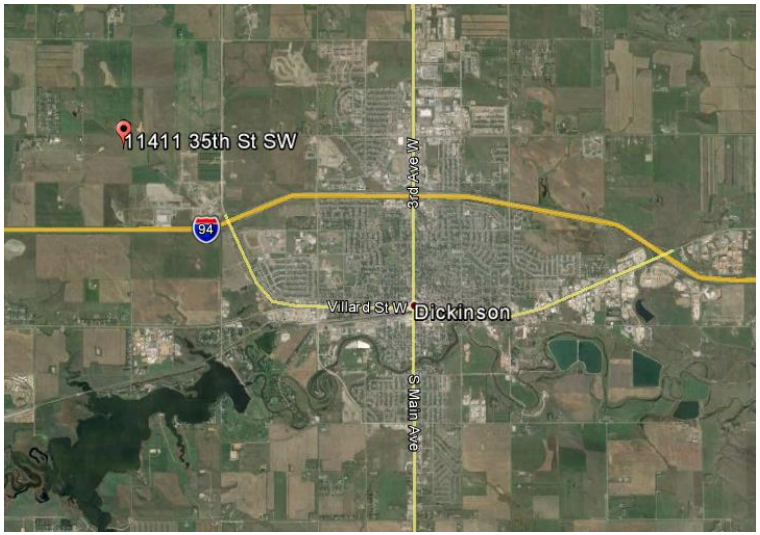
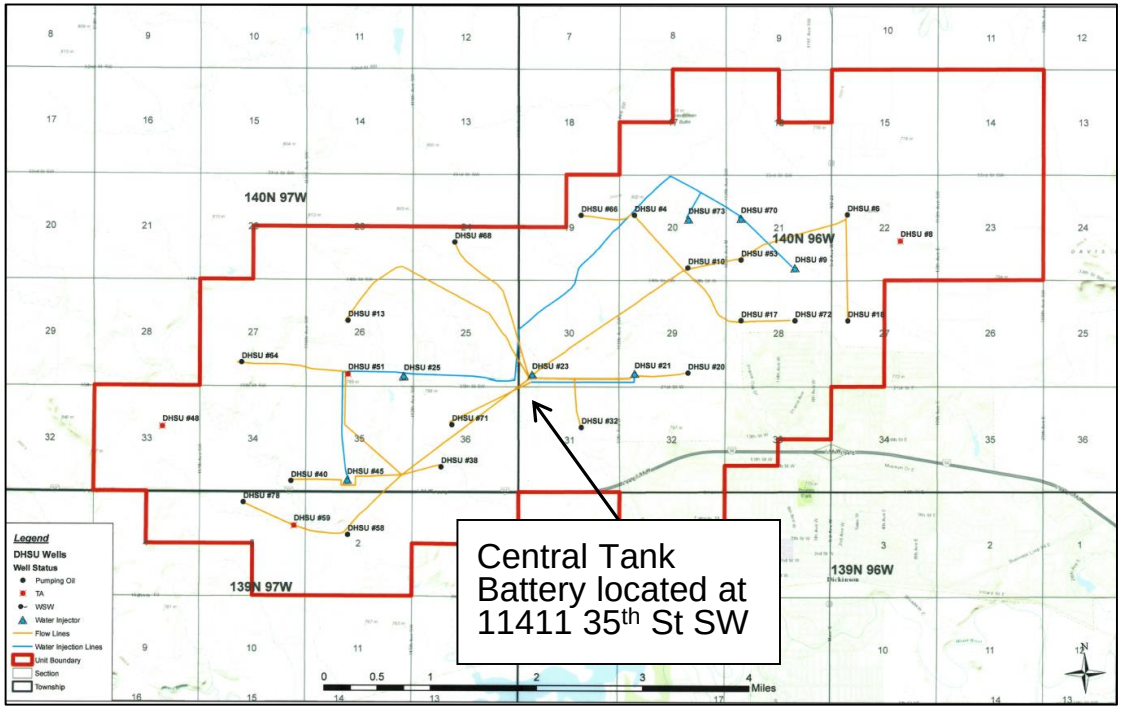
Overview of C12 DHSU Assets

- 140+ BOPD production capability (8/8ths)
- Unitized conventional field
- Recovery to date: ~26.6 MMSTB; 43% of OOIP
- ~78% NRI and ~97% WI
- 28 wells:
  - 17 Producing
  - 5 Injection
  - 4 wells T&A'd
  - 1 source water well
  - 1 disposal well
  - 0 Shut-in for mechanical integrity (low P&A liability)
- Identified improvement opportunities
  - Lower lease operating expense through capital projects
    - Pipeline replacement and water pump upgrade
  - Artificial lift optimization
  - Water shut offs
  - Re-pressure reservoir with source water well
  - Waterflood optimization
  - CO2 EOR development
    - Estimated 7+ million barrels of CO2 incremental oil

Field Location





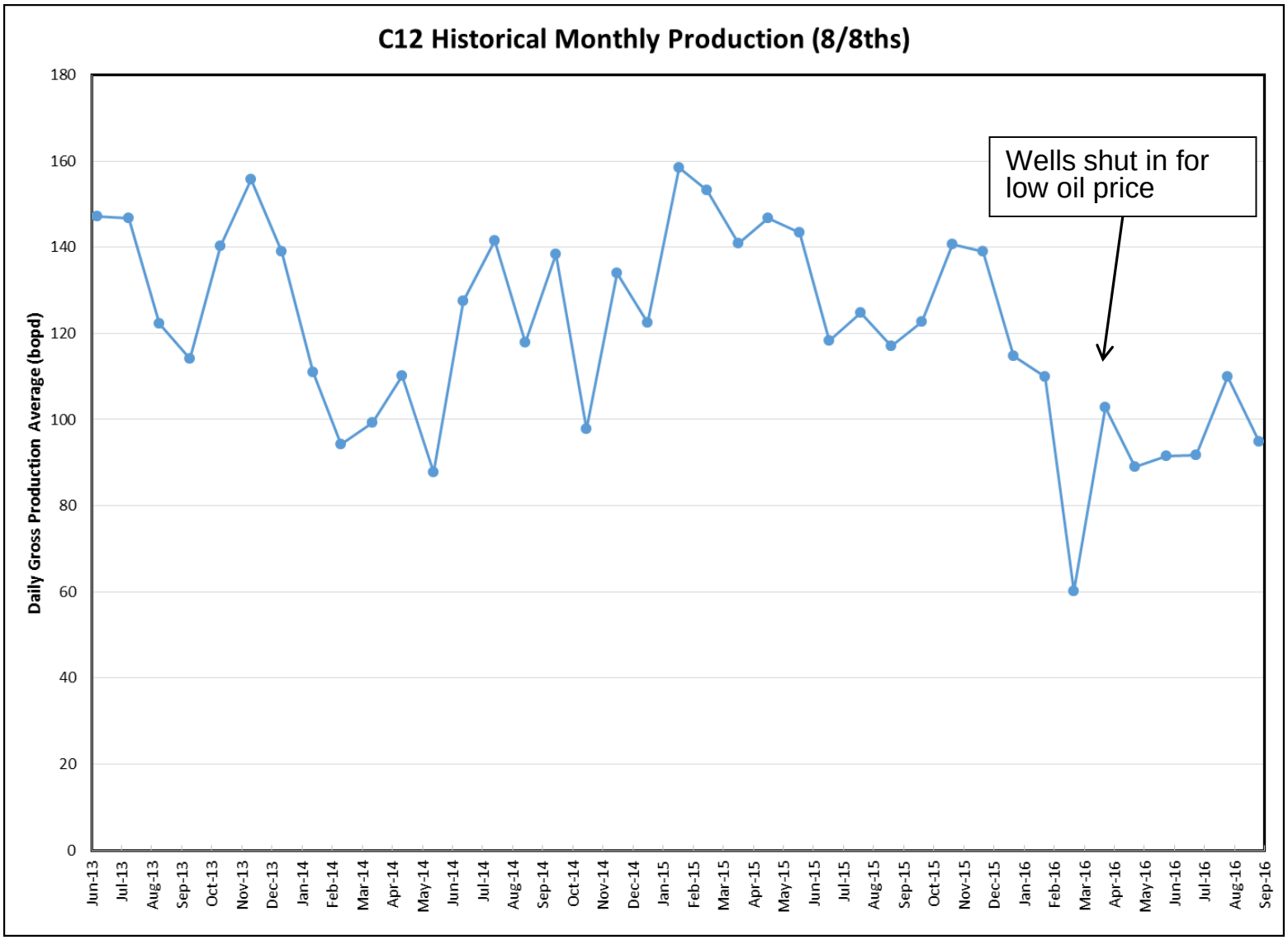


Dickinson Heath Sand Unit Overview

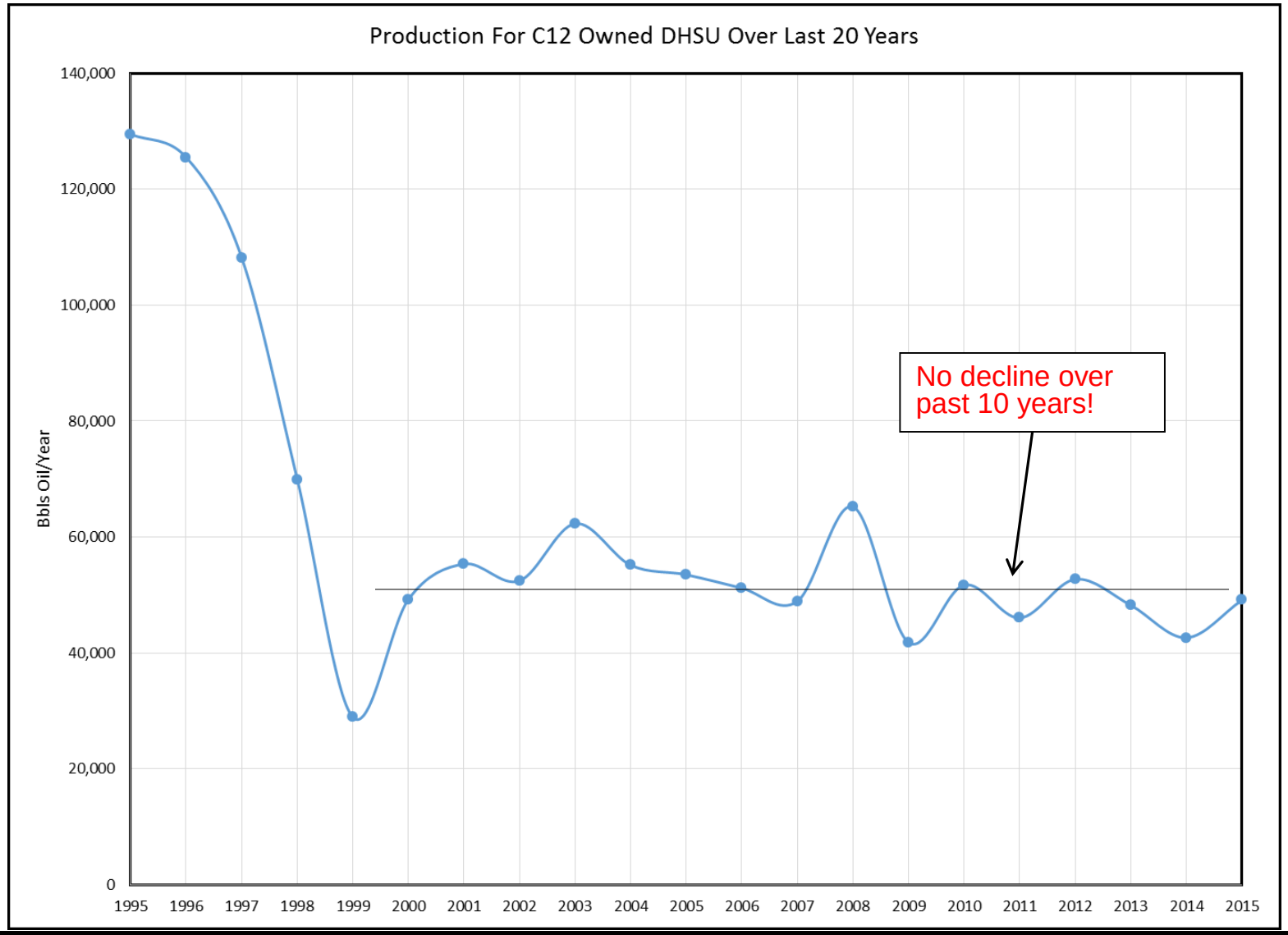
- Discovered 1958
- Field unitized in 1973
- Water flood developed in 1973 on 160 to 320 acre spacing
- Field is 8 miles long by 2.5 miles wide
- Recovery to date ~ 26.6 mmboe (43% of OOIP)
- OOIP of 61.8 million bbls (total field)
- 68 wells have been drilled into the Dickinson Heath Sand Unit
- Produces from the Tyler Sandstone
  - 7900' TVD
  - Divided into an upper "A" zone and lower "B" zone separated by a shale break
  - Main production is out of the A2 and B1 sands

Tyler Sand Package	K Range (md)	K Avg. (md)	Φ Range (%)	Φ Avg. (%)	Net Sand Avg (ft)
A1	0.01-642	56.0	0.5-19.2	10.6	0.1
A2	0.01-1764	204.0	1.1-21.5	13.4	2.0
B1	0.01-3150	158.0	0.5-20.7	14.0	4.2
B2	0.01-545	294.0	0.8-19.6	14.9	.5
K cut-off based on 0.1 md.					
Φ cut-off based on 7% porosity					

C12 Historical Monthly Production (8/8^{ths})



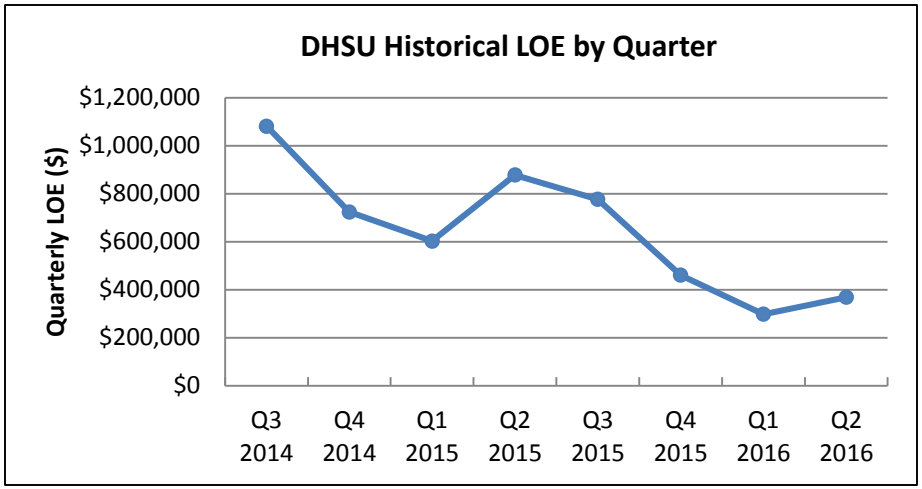
C12 DHSU Historical Yearly Production

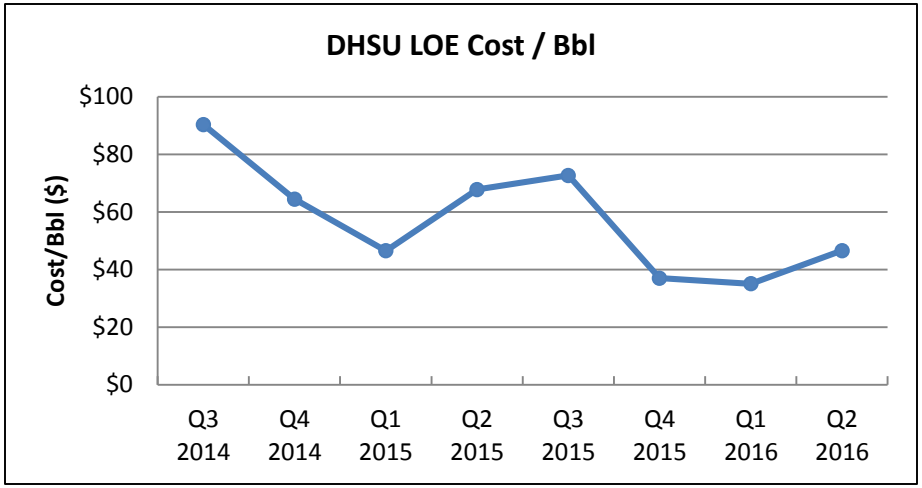


Lease Operating Expense

C12 has continued to reduced LOE from:

- Investments
  - Fixing things right the 'first time'; reduce repeat failures including:
  - Installed ~9000' of new pipeline
  - Replaced 2x 500 bbl water tanks
  - Swapping all pumps to mechanical hold down
- Renegotiated contracts >$2000
- Moved to single chemical vendor
- Shut-in uneconomic wells, reducing chemical and utility costs
- Have identified addl. opportunities to reduce LOE and improve oil production





Field Improvement Opportunities

- Replace Water Plant Pumps ($6000/month Savings)
  - Currently have 3x 300 HP pumps used to re-inject produced water back into reservoir
  - Pumps are old (30+ yrs) and consume significant maintenance cost and utilities
  - Estimate it would cost ~$150,000 to replace pumps with new injection skid with 1x 150 HP pump and filtering system
  - Expected LOE savings from utilities and maintenance ~ $6000/month
  - Payback in ~**24 months**
- Increase VRR (+35 bopd)
  - Field has only re-injected produced water
  - Pressure has declined as a result
  - C12 had source water well assigned to it in 2014
    - Costs $5000/month to run ESP in source well
    - Additional $3000/month to run water plant pump
  - Would take 18 months at 4000 bbls/d additional injection to see a 25% increase in production
  - Expected production after raising reservoir pressure to 4000 psi is 175 bopd
  - Payback in ~ **2 years**
- Acidize (+10 bopd)
  - Numerous wells not stimulated in many years
  - A review of wells indicates ~4 wells are acidizing candidates
  - Acid job cost per well = $15,000
  - Expected initial boost in production = 30% per well or 10 bopd total
  - Payback is ~ **7 months**

CO2 EOR Development Potential

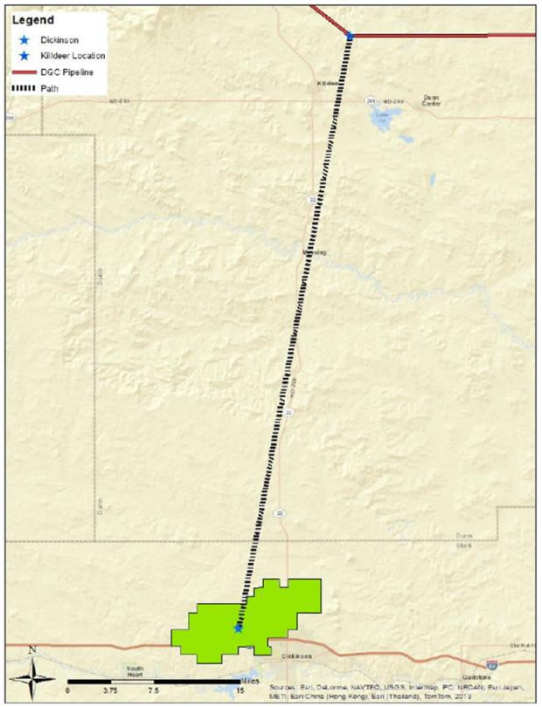
Dickinson Heath Sand Unit

Development Plan

- Obtain CO2 contract from DGC (Dickinson Gasification Company)
  - Secured CO2 supply with contract with DGC in 2016
- Build Central Processing Facility for fluid processing & recycle compression
- Build 40 mile pipeline from Killdeer to Dickinson
- Re-pressure reservoir to 3000+ psi (miscibility pressure ~ 3000 psi)
- Install new field flowlines; workover wells as needed to implement CO2 EOR flood

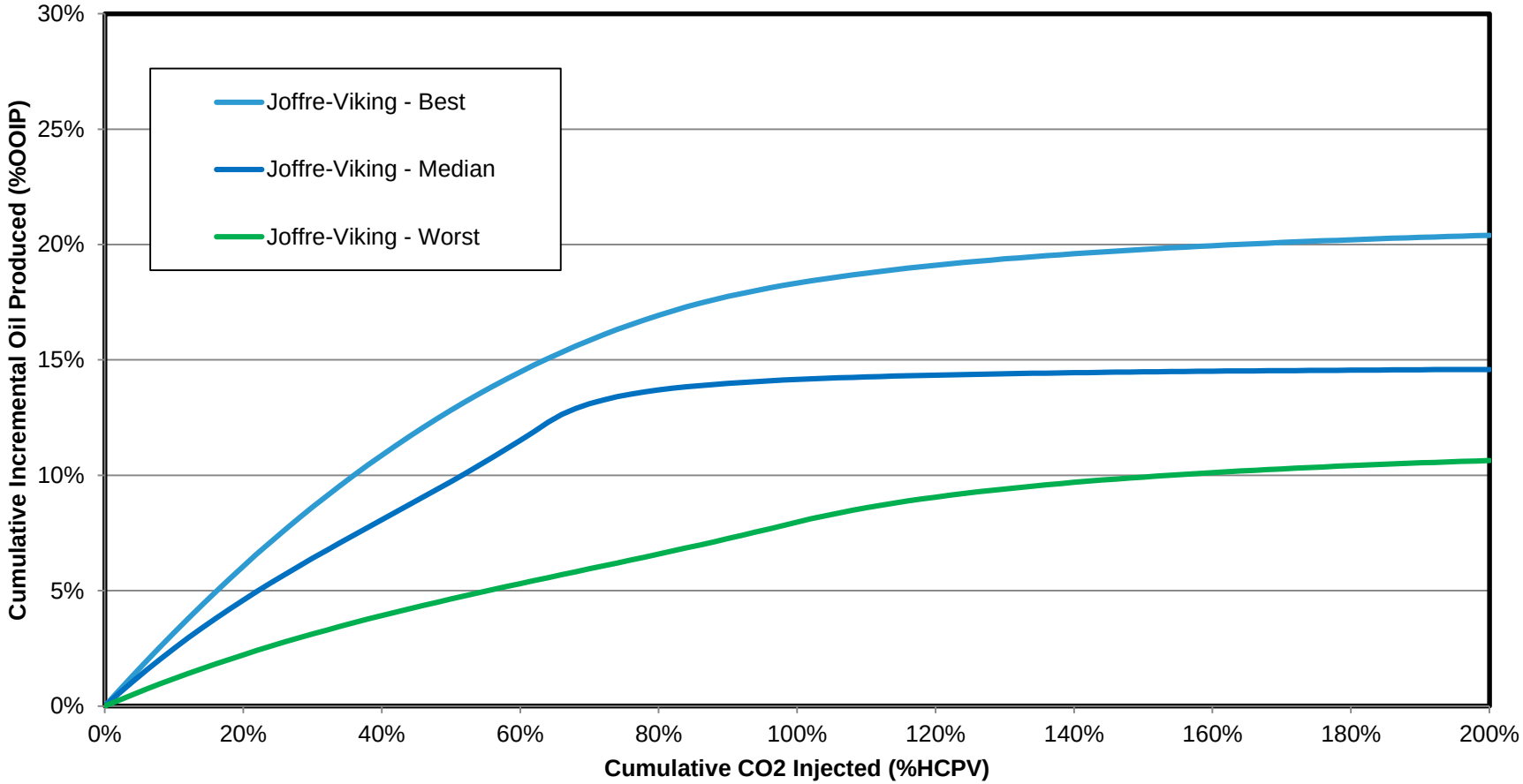
Reserves	7.1 MMSTB (11% RF)
IRR	+24% *at $70/bbl WTI*
NPV	$105 MM *at $70/bbl WTI*
Development Cost	$244 MM *(gross)*

Pipeline route from DGC CO2



Appendix

Comparable Type Curve used for DHSU



DHSU EOR Development Plan